TITLE: NGCAS _ Next Generation Capture and Storage

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Abstract
The Next Generation Capture and Storage Project (NGCAS) developed and tested a methodology and subsurface modelling tools for CO2 storage site selection, evaluation and risk assessment. It studied issues associated with the geological storage of CO_2 emissions from a refinery in Scotland in onshore coalfields and offshore oil reservoirs. One aim of the project was to devise a workflow leading to the analysis of the risks associated with CO_2 storage in depleted hydrocarbon reservoirs. Its scope included : documentation of the methodology for assessing storage sites; evaluation of the potential to co-optimise storage and EOR performance; development of a methodology for modelling and quantifying the risk associated with long term storage of CO_2 in an offshore oilfield.
By taking regional data and developing scenarios for boundary conditions pertinent to the reservoir the study was able quickly refine models for CO_2 movement over a timescale of 1000 years. The models indicated that in the most realistic "base case" CO_2 migrated by only 50m vertically by diffusion, and that even in a "worst case" where seal efficiency was poor, any stored CO_2 moved a maximum of 350m vertically through Overburden in 1000 Years, and by lateral advection in the aquifer by no more than 6m in 1000 Years. The major risks were identified as well integrity and overburden characterisation.

Introduction
The NGCAS project was initiated to study the feasibility of safe geological storage of CO_2 from BP's Grangemouth refinery within onshore coalfields and offshore oil reservoirs. It was jointly funded by European Union's Energy and Transport Directorate (DG TREN) and by the CO_2 Capture Project (CCP); the CCP is an international Joint Industry Project to research and develop technologies aimed at reducing the cost of CO_2 separation, capture and geological storage.

The scope of NGCAS was to :-

- Document the methodology for assessing storage sites
- Evaluate the potential to co-optimise storage and EOR performance
- Develop a methodology to assess the risk associated with long term storage of CO_2 in an offshore oilfield

The principle aim of the project was to develop a methodology for the modelling and analysis of the risks associated with CO_2 storage in depleted hydrocarbon reservoirs.

This paper describes in overview the tools used and the workflows undertaken; it reviews the findings and presents some conclusions and recommendations for further work.

The nine participants in NGCAS were: BP (Coordination), STATOIL (Tech. Transfer), British Geological Survey, Geological Survey of Denmark & Greenland; Institute Francais du Petrole, Exploration Consultants Limited, Ceimat, FZJ, and IEA Greenhouse Gas R&D Programme.

CO_2 Source Selection - The Grangemouth CO2 Emission Reduction Project

Initiated in 2000, the intention of NGCAS was to test the potential for the geological sequestration of large volumes of anthropogenic CO_2 captured from industrial plant. Site selection involved screening and assessing storage options closest to CO_2 sources. The NGCAS project addressed emissions from a refinery in Scotland; onshore storage options were assessed first (because of their proximity and potentially lower cost) then offshore storage options and enhanced oil recovery in North Sea fields was explored. BP's Grangemouth refinery and petrochemicals complex, 30 km west of Edinburgh in Scotland, was already the subject of a study to determine CO_2 capture costs. The Grangemouth complex emits about 4 million tonnes of CO_2 annually; in addition there are the nearby Longannet and Cockenzie coal-fired power plants, which in combination emitted about 11 Mt CO_2 in 2000. By this reasoning the Grangemouth site was identified as the central source of CO_2 for the case-study.

The quantity of CO_2 to be produced over a period of 25 years was estimated to be roughly 100 million tonnes of CO_2 by direct emission; in order to capture half of this at a rate of 2Mt/year for storage the necessary plant would emit a further 600,000 tonnes/year of CO_2 (Simmonds et al. 2003). Taking into account the emissions from the capture plant the net CO_2 avoided would be 1.4 million tonnes/year and the net emission reduction would be 35%. Simmonds et al. (2003) estimate that this might cost about \$50-60/tonne CO_2, representing a total cost of about \$100 - 120 million/year. However, the cost is sensitive to the price of hydrocarbon gas and the prevailing cost of CO_2 capture. This projection for Grangemouth suggested that any storage site should be able to accommodate 2Mt of CO_2 per year and have a total capacity of over 50 Mt CO_2. The study would be projected to 1000 years of storage. The priorities for selecting a site were determined to be safety and security of storage followed by economic feasibility. Public acceptance of any subsequent scheme would be outside the scope of this technical study.

CO_2 Sink Selection – Onshore or Offshore?

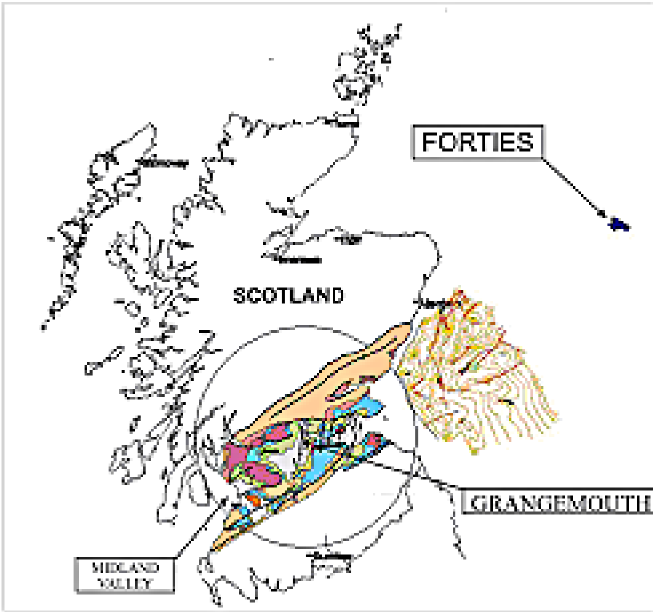

Figure 1. Location of the Grangemouth plant, Midland Valley of Scotland (coloured), Forth Approaches Basin (contour map) and Forties oilfield.

Onshore Storage – The Midland Valley of Scotland
(TP: British Geological Survey)
The area immediately around the Grangemouth plant is known geologically as the Midland Valley of Scotland (MVS). It is a structurally complex graben 90km wide (N-S) and 300km (E-W) long, bounded by major faults and encompassing four synclines containing Carboniferous sands and coals. It is bounded to the North by the metamorphic and igneous rocks of Scottish Highlands and to the South by the Southern Uplands of Scotland, which comprise highly deformed Palaeozoic sediments. Neither of these adjacent terrains has any potential for CO_2 storage.

It is the home to nearly 4 million people (including the cities of Edinburgh and Glasgow), has a long history of industry and mining and is increasingly the source of groundwater abstraction for industry and drinking. There are many coal mines and more than 100 boreholes deeper than 700m – the depth at which CO_2 phase-change was predicted to occur, but only 40 with good petrophysical data (Browne, Arkley & Holloway, 2002).

The study performed by the British Geological Survey looked at the storage potential of both the sands and the coals within a 100km radius of Grangemouth, including those below the seabed of the Firth of Forth.

Storage of CO_2 in Sandstone Saline Aquifers

A good storage formation for CO_2 should have sufficient permeability to support extended periods of injection at practical rates, and enough porosity to store the required amount of gas.

The sediments of the MVS older than the Old Red Sandstone were considered to have no reservoir potential, sediments younger than Carboniferous have insufficient overburden or caprock, hence both they and any indurated Carboniferous limestones were excluded from the study. The majority of sandstones in the MVS have fair porosity, only low primary permeability, but can have high secondary permeability through fractures.

The borehole data penetrating the Devonian and Carboniferous sandstones indicate a lack of porosity and permeability at the required depths (e.g., <1mD and 10% porosity) (Browne, Arkley & Holloway, 2002).

In the offshore extension of the MVS there was significant uncertainty over the quality of the caprock and hence this was also ruled out.

Storage of CO_2 in Coals

Coals of Namurian and Westphalian age occur widely in the MVS and are distributed through six major coalfields.
The study considered coals in the Clackmannan Syncline and those in a Coal Bed Methane (CBM) project at Airth (Creedy 1999) , 7km from Grangemouth (Bacon, 1995;Envoi 2003).
The coals of the Clackmannan Syncline were ruled out as being of insufficient permeability, those of the Airth CBM project proved unsuitable too: in the CBM field at Airth it was determined that even the most ambitious plan of the operator would result in insufficient capacity to adsorb significant amounts of CO_2 in what is still a relatively impermeable coal (e.g., compared to US examples). The CBM field is densely mined and faulted, making migration and leakage a strong possibility; the many historic penetrations of, and migration pathways within, the coal seams increase the risk of migration. In addition to the storage and integrity issues it was found that the net impact of displacing Methane with CO_2 would result in increased procedural complexity since the Methane would need to be captured efficiently if the effects of CO_2 storage on warming potential were not to be negated. Economically such long-term storage would have the adverse impact of removing that coal from the reach of subsequent exploitation.

As a consequence of these results the Onshore geological storage potential in Scotland was downgraded due to the poor characteristics of potential storage formations. The sandstones have poor reservoir characteristics (porosity, permeability) and seal. Coals were downgraded due to low permeability and leakage risk via abandoned mine workings and boreholes. Thereby the Midland Valley and its offshore extension was downgraded as suitable site for sequestration and the project subsequently focussed on the Forties oilfield.

Forties – Simulation of the effects of CO_2 injection on hydrocarbon production

The Forties Field
The Forties field lies almost 180 km (112 miles) east-northeast of Aberdeen, Scotland, mostly in block 21/10 of the UK sector of the North Sea. It was discovered in 1970 by BP Exploration and in 2003 it was sold to Apache Corporation. It covers roughly 90 km^2 and at the time of its appraisal was estimated to contain 4 billion barrels of oil. Since its discovery 190 wells have been drilled into the reservoir.
Geologically it consists of a number of Palaeocene sand bodies of submarine fan origin connected to one another to varying degrees and separated by mudrocks. The sedimentary facies within the fans are also varied and result in significant heterogeneity. The Charlie Sand is a large partially isolated unit on the upper west side of the reservoir.
The original oil water contact was at 2217m subsea, with 155m of Hydrocarbons. The aquifer is roughly 300m thick. Upon discovery the reservoir pressure was close to hydrostatic (c.22 MPa or c.3200 psi) and the formation temperature was 96degC (205degF). Forties production is transported via the Forties Pipeline System (FPS) to landfall at Cruden Bay in Scotland and thence ultimately to Grangemouth, a total distance of about 380km (236 miles). Forties was estimated to have the potential to store over 75Mt of CO_2 (Espie 2001).

Enhanced Oil Recovery and CO_2 Storage - WAG Simulation Study
(Bennison, 2002)

A precursor to the study of the movement of stored CO_2 in the Forties reservoir system was to investigate the economic effect of injection during the late-stage oil-production phase of the field's life.

The study used a 7 component numerical model of the Forties "Charlie" sand run in the commercially available VIP^{tm} (Landmark) compositional simulator. In the simulation the reservoir was initially waterflooded and then subjected to a number of alternative Water Alternating Gas (WAG) procedures where CO_2 was the injected gas. The sector model provided by BP represented 1500m x 500m x 38m of the reservoir, sliced into 76 layers each divided into 60 x 5 areal blocks. A total of 22800 blocks of which 16618 were active.

The hydrocarbon volume expressed as barrels "Stock Tank Oil Initially In Place" (STOIIP) was 17.8MMstb, where the hydrocarbon pore volume was 21.3MMrb of 26.3MMrb total pore volume. There were two wells in the model, injector and producer, one at each end. The model was run from 1976 until 2005 and produced 3% of initial STOIIP per year, the pressure was maintained at 3000 psia (20.7MPa) by water injection. The CO_2 WAG was one of five production scenaria then run from 2005 to 2050.

The simple alternation of water and gas over 10 cycles gave an increased production over pure waterflood of 6.5% and resulted in nearly 25% of the original hydrocarbon pore volume (HCPV) being filled by CO_2, but this was bettered by relocating the injector and finishing with gas injection. This case gave a 50% HCPV filled with CO_2 and nearly 10% more oil recovery, producing nearly 83% of the original oil. What is important to note is that the best case required about 1.2 pore volumes of gas to be injected, indicating the need to accommodate significant levels of gas recycling.

Having established at the reservoir scale that CO_2 injection need not be to the detriment of oil production, and that significant quantities could be stored, the project moved on to assess the risks associated with storage over 1000 years.

Regional Flow Modelling

NGCAS conducted a case history for site selection, characterisation, modelling and risk assessment for the Forties Oil field in the North Sea. Oil Industry seismic and well data were used in conjunction with 5 advanced modelling tools ranging from two dimensional basin models to three dimensional regional and field scale models. These were integrated with Risk Assessment Studies.

The study of basin-scale fluid-flow was intended to underpin risk assessments associated with the migration of CO_2 as CO_2-charged-water in the regional aquifer. It looked at aquifers and aquitards along a 250 km (155 mile) east-west section which passed within 20km (12 miles) of Forties. The intention was to start at the basin scale and to establish boundary conditions for subsequently finer scale and more localised modelling.

Regional Seismic interpretation
(Kirby, 2003)

The western part of the seismic profile along the section described above was interpreted to reveal the complex nature of the basin fill. The lowest picked horizon was the Variscan (Top Carboniferous) unconformity.
The interpreted section is dominated by two basic subdivisions: Mesozoic (Jurassic and thick Cretaceous Chalk) post-Cretaceous including the Forties fan-system and its thick mudstone overburden. The pre-Chalk systems are largely isolated from the superimposed sediments by the extensive and largely unfaulted chalk.

The lithologies above and around the various Forties fan lobes are predominantly mudrocks with minor discontinuous sandier units. The Forties itself is the top of a stack of basin floor fans which prograde from the east. There is some evidence that the Forties Charlie sand is in part contiguous with the sandier parts of the Dornoch delta and entrained fluids may be able to move laterally with regional aquifer flow.

This stratigraphy was used in subsequent basin modelling processes.

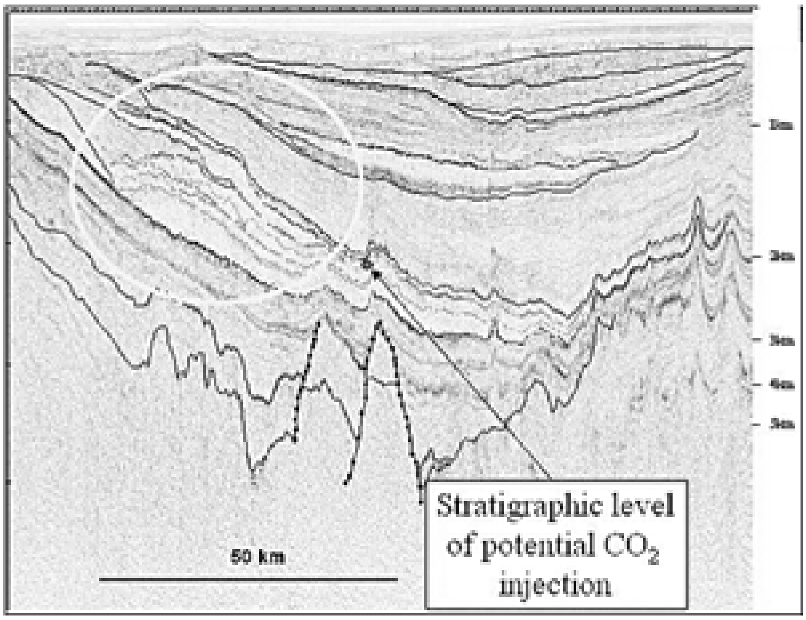

Figure 2. Interpreted seismic profile. Potentially sandy units in yellow. Data courtesy of WesternGeco

Regional Basin Modelling
(Bidstrup, 2003)

The aim of the 2D basin modelling was to give an indication of the rates and extents of natural pressures and fluid flows during the evolution of the basin. This was achieved by taking the lithostratigraphy and populating it with parameters for porosity and permeability derived from a seismic inversion technique (J Bunney, 2002). The most likely outcomes of this modelling were to be used to establish the most probable boundary conditions for modelling of the field itself.

The first stage was to convert the seismic section from time to depth using seismic "check-shot" data from nearby wells. The section was then extended to the west in order to establish whether any migration pathways cropped-out on the seabed closer to the Scottish mainland.

The final 2D model consisted of 62 layers or "events" and 108 grid points. Each modelling scenario consisted of a variation in parameters controlling lithology, porosity, permeability, duration and various points along the section.

In the "Base Case" for CO_2 storage the base-Jurassic was assumed to be the lower limit for significant fluid flow. The Jurassic is predominantly an oil-prone mudstone source rock.. This is overlain by less organic Cretaceous mudrocks with a proportion of carbonate, and these by the thick Cretaceous Chalk limestone. Above the Chalk are the various sandy (e.g., Forties) and muddy (e.g., Hordaland) units of the Tertiary. In the "base case" two centres of overpressure (pore fluid pressures above hydrostatic) developed: one below the chalk and the other at a shallower depth in the Cenozoic. In the Forties Fan sands the fluids are overpressured by as little as 0.4 MPa/100km.

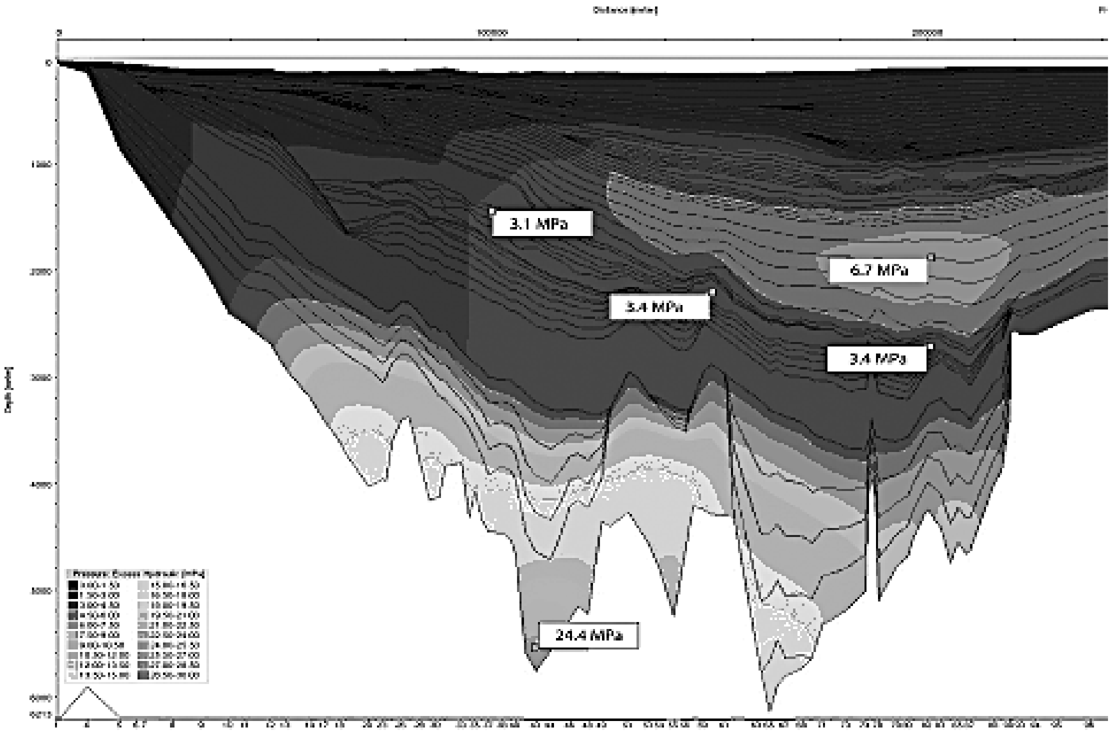

Figure 3. Calculated overpressure distribution for the "base case" model show two separate centres of overpressure - one in the Cenozoic and one in the Jurassic/Lower Cretaceous

In order to test the sensitivity of the system to differences in lithology and history 11 different cases were run.
They included: adding more shale to the fan sands; reducing or increasing rates of Quaternary sedimentation and hence loading on the system; removing the effects of hydrocarbon generation in the Jurassic; and increasing the vertical permeability of the Cenozoic overburden by a factor of ten.

The overall conclusion was that pressure changes in Jurassic formations had little effect on the Palaeocene where pressure was most dependent upon the permeability and rate of deposition of the Tertiary mudstones. If the communication with the overlying Dornoch was explicitly modelled the pressure that resulted in the Forties was in close agreement with measured well data and published regional data (Moss et al 2003).

The pressure gradient across the basin is very stable and the model showed a strong case for pressure being close to hydrostatic with overpressures of less than 1 MPa/100km (average 0.5 MPa/100km). This case produced very low aquifer flow rates; even less than the published 330m/1000yr produced by a regional difference of 10Mpa (Crawford et al 1991).

The near-hydrostatic case was selected as the best set of boundary conditions to use in the subsequent 3D modelling.

Forties Field - 3D Modelling of Potential Escape Routes
(Ketzer, J.M. & Carpentier, B. 2003)

The workflow employed to model the potential advective and diffusive escape routes from the reservoir was broken into two basic stages: 1) using a 3D basin modelling tool (Temis3D) to simulate fluid flow in the reservoir and its adjacent stratigraphy; and 2) using a multi-phase fluid flow simulator (SIMUSCOPP) to model the interaction between stored CO_2 and the surrounding rocks and fluids.

Each process was refined and constrained by the boundary conditions determined in the preceding process. The initial assumption was that, following a period of CO_2 WAG or other injection process, that the Forties reservoir was completely filled with supercritical CO_2.

The geological setting has been described previously. For the purposes of the model the Forties reservoir is an anticlinal trap filled to the spill point and with no large or significant faults in the overburden. At this stage no well penetrations were included in the model.

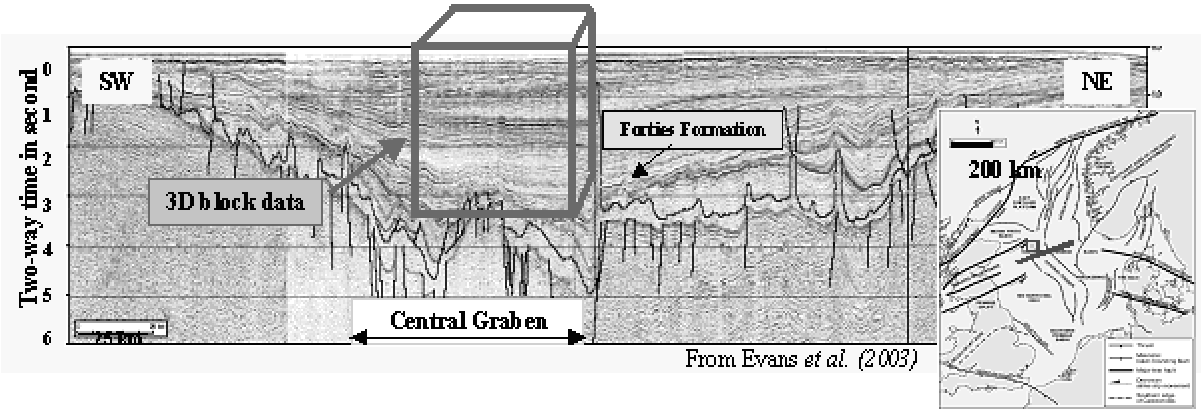

Figure 4 : 3D block location map

Forties 3D Model - Temis3D Field History Simulation

The Temis 3D tool is designed to simulate compaction, source rock maturation and hydrocarbon migration, but can easily be configured to model the single phase water flow in terms of pressure, magnitude and direction in each layer.

The data used to populated the Temis3D model came from an extensive data-mining exercise performed by BP. It included ten vertical depth maps, high resolution petrophysical data from well logs, cores and the inversion of a 3D seismic data volume.

The model was gridded to represent nine seismically derived layers and 31 interpolated layers in a 400m x 400m block of the reservoir and overburden; 14 of the layers were concentrated in the reservoir to facilitate the importation of high resolution lithological and petrophysical data. The main constraint was Computer power. Modelling operations of this type make intensive use of the capabilities of modern computers.

The cases run started with a “base case” using the most realistic data and proceeded through a series of 12 scenaria to represent various sensitivity cases. The aim was to identify the most serious risks of leakage and to concentrate upon them at a later stage.

The results suggested that modern day water flow in the reservoir’s aquifer is predominantly horizontal from SE > NW with velocities lower than 500m/Ma. The flow in strata below the reservoir is only 10m/Ma and above the reservoir in the overburden it follows two behaviours: 1) deeper than 1400m flow in the model is largely downward in the range 10-30m/Ma. 2) In higher parts of the overburden (above 1400m) it flows upward at a rate of 60-150m/Ma.
Even in the worst of the modelled scenaria the fluid flow was still too slow to remove a significant amount of CO_2 from the reservoir. It only moved 8m horizontally in 1000 years.

As a result of these studies the initial boundary conditions for SIMUSCOPP were set as hydrostatic.

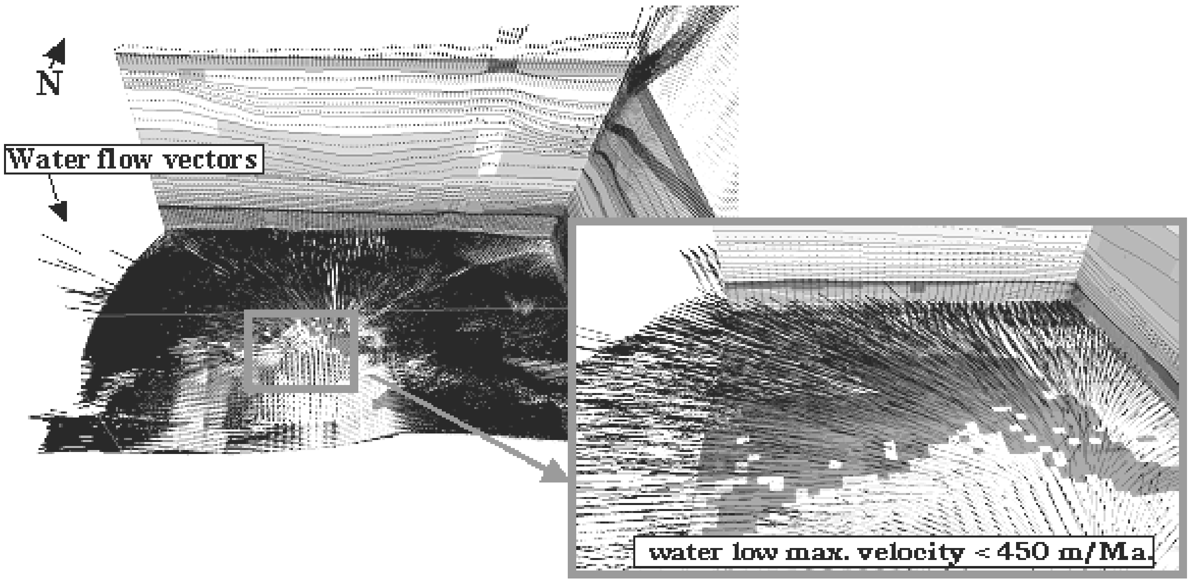

Figure 5. Temis3D fluid flow distribution at present day (base case)

Forties 3D Model - SIMUSCOPP Fluid Flow Simulation

SIMUSCOPP uses Darcy's law and mass-conservation to simulate pressure and saturation of each of three phases across the model.
The program can model CO_2 diffusion and dissolution in the water phase as well as adsorption onto rock. It does not however model geochemical interaction. It computes initial conditions from capillary-gravity equilibrium and then solves for the evolution of pressure and saturation over time. The data used to initiate the 3-phase compositional simulator were derived from previous modelling and the physical characteristics of the CO_2 as entered from user-defined equilibrium constants, published thermodynamic properties, and computed equilibrium solubility.

The flow parameters used in the reservoir were multiphase and derived from the original reservoir model, those used for the mud rock overburden were derived from the classical van Genuchten relative-permeability:capillary-pressure relationships (van Genuchten 1980).
The initial conditions assumed original reservoir pressure and a uniform 50% CO_2 saturation in the reservoir. For the overburden the residual gas saturation in the SIMUSCOPP runs was set to 20% and the critical gas saturation was set to 5%.

Owing to the increased complexity of SIMUSCOPP's modelling process, which includes capillary-pressure and relative-permeability parameters, any model based on the same grid block size as Temis3D needed to be smaller in extent. Maintaining the grid block size was crucial to any subsequent upscaling.

The rationale in the SIMUSCOPP modelling was to model the "base case" and to identify a feasible "worst case" scenario of parameters that would lead to maximum leakage over 1000 years and to determine that rate of leakage.

In the "base case" model no CO_2 breaks through the capillary entry pressure of the overlying mudrocks. CO_2 in the overburden escapes only via diffusive processes into the first 50 m above the reservoir. Some also escapes downward as CO_2 saturated water due to a density contrast with the underlying aquifer, the waters of which are undersaturated with CO_2. After 1000 years only 3.6% of the original CO_2 had moved to any degree from its original position and none had reached the surface.

In the "worst case" model, which assumed zero pore entry pressure into the overlying mudstones (i.e., they did not act as a barrier at all) about 37% of the CO_2 migrated toward the surface as a gas, in the dense supercritical phase and as an aqueous solution. The SC-CO_2 rose almost 175m, and that CO_2 dissolved in water rose 350m through the c.2000m of overburden in 1000 years.

Since even in the very worst case of geological seal failure the CO_2 only migrated vertically by 350m it is reasonable to assume that under prevailing "base case" circumstances only minimal CO_2 movement is to be anticipated.

Risk Analysis
(Wikramaratna, R. S and Wickens, L 2003)

The final part of the NGCAS project was a Risk Assessment (RA) of the long-term storage of CO_2 in depleted North-Sea oil reservoirs. The workflow could easily be modified to tailor the process to other situations and geographical regions. The risks were associated with release to the surface or into other significant geological strata such as potable water aquifers.
The RA built on the results of the previous stages in the workflow.
There were two main parts of the RA:-

1 - The RA began with categorisation of probable pathways for migration and release by identifying, but not prioritising, Features Events and Processes (FEPs) that might lead to a release.

2 – the RA then used analytical models and numerical simulations to quantify the bounds on rates of release and relative risks associated with each potential migration pathway. In each case the workflow aimed at finding the simplest effective method to quantify each FEP.

Risk Analysis - FEPs

The FEPs can best be summarised schematically (Fig). They fall into three groups: -

1. **Sequestration** – risks associated with storage processes;
2. **Escape** – risks associated with the behaviour of stored CO2;
3. **Migration** to Surface – risks associated with the nature of the migration pathways and behaviour of CO2 in that environment.

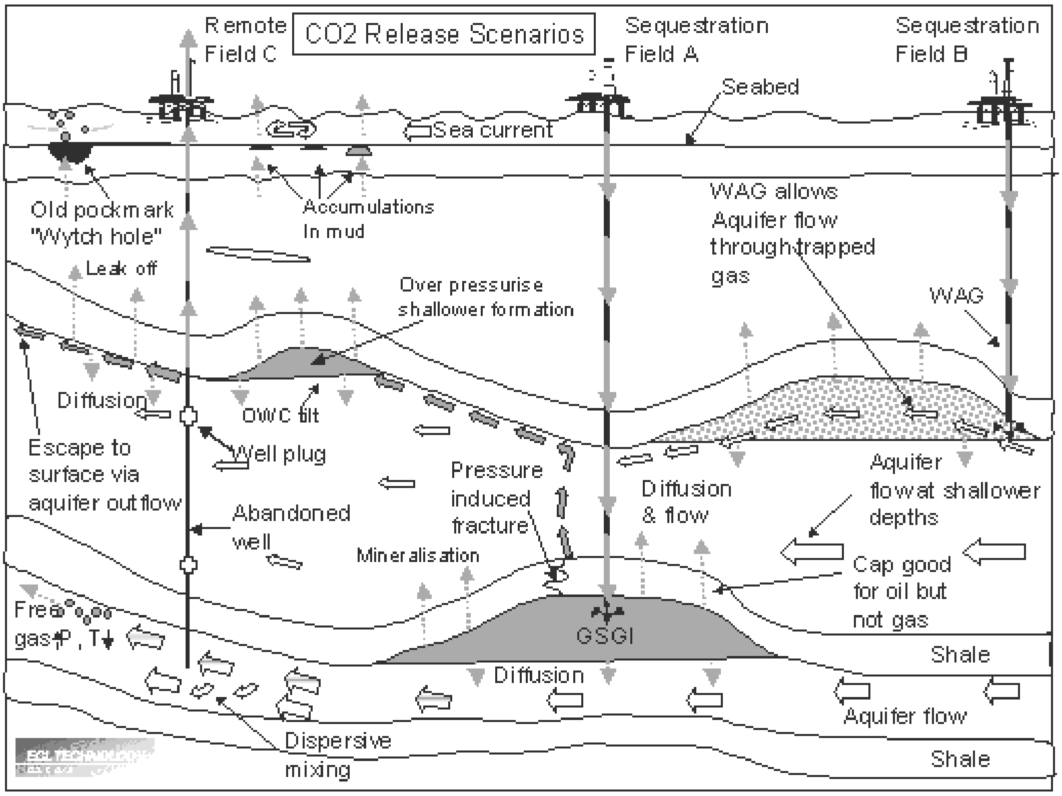

Figure 6. Schematic of the key FEPs that need to be considered when assessing the potential release paths and release rates of CO_2 sequestered into a sub-sea oil reservoir.

Risk Analysis - Assessment of Risk

The pathways and interactions can be usefully represented by a fault-tree in which the FEPs can be used to compute release rates for each scenario.

Risk Analysis – The Forties Field

The risks identified in Forties also fell into three groups:-

1. Pathways through the underlying aquifer
2. Pathways through the overburden
3. Pathways associated with wells

1- Pathways through the underlying aquifer

The study considered pathways into the aquifer for both convective and diffusive transport of dissolved or supercritical CO_2, with or through the aquifer water.
It concluded that the advective flux of dissolved CO_2 in the aquifer was insignificant compared with the stored volume and that the distances travelled were insignificant compared with the size of the reservoir. Studies of diffusive flux showed it to be even less significant than advective flux.
If liquid CO_2 entered and was entrained in the aquifer the very low rate of aquifer flux would cause it to make no significant contribution to migration over 1000 years.
The only other risks associated with aquifer leakage are associated with the process of injection. They were identified as firstly the possibility of high CO_2 injection pressure leading to downward displacement; and secondly the possibility of over-filling the reservoir leading to CO_2 escaping past

the low structural spill-point. It was concluded that an injection strategy would be designed to take account of these risks and plan to avoid them.

2 – Pathways through caprock and overburden

For CO_2 to penetrate the overburden the most evident risk would be a change in pressure which caused the CO_2 to exceed either the capillary entry pressure or the fracture pressure. This might be caused by either the change in pressure as liquid CO_2 replaced denser oil or transient high pressures around active injection wells. Both these were determined to be unlikely and relatively easy to monitor and plan to mitigate.
Vertical diffusive flux of CO_2 was shown to be negligible and earthquakes are likely to have a minimal risk based on historical data.
Vertical leakage caused by chemical interaction of CO_2 with the caprock is considered to be negligible based on existing CO_2 -rich reservoirs, but is sufficiently indeterminate over these long time scales to warrant further study.

Overall it was considered that risks associated with caprock/overburden leakage were unlikely.

3 **– Pathways through wells**

Wellbore leakage of CO_2 represents the biggest remaining area of uncertainty in the risk analysis. Nearly two hundred wells of varying types penetrate the Forties field.
Numerical studies of pressure changes in wellbores were carried out and also on the effect of those changes on cement plugs of poorly known composition and integrity.

Risk Analysis – Conclusion

1 - The RA study concluded that further work was required to audit wells and to investigate the CO_2 +water+steel+rock interactions over the lifetime of a storage project. They should also investigate the behaviour of CO_2 rich fluids entering and migrating up a borehole. Such studies would have a significant bearing on storage options and future well abandonment and completion procedures.

2 – The risks associated with escape into undrilled overburden are negligible with the proviso that more work is needed on caprock+CO_2 chemical interaction.

3 – Transport of CO_2 down into the underlying aquifer has been shown to have no long-term significance. The short-term risk associated with the period of injection can be mitigated by appropriate planning and procedures.

Conclusion

The NGCAS project was primarily a case-study of the duration and security of storage in a real hydrocarbon reservoir with a rich data set and a methodology for site-selection. It shows that it is important to characterise the storage system at both basin and field scale in order to characterise the site, and to conduct risk assessment including geological migration (leakage) pathways. The geological and hydrological framework needs to be understood together with the geological evolution through time.

The workflow developed by the participants was novel in that it was a reversal of the traditional geological and reservoir modelling procedure of "grid coarsening" during the development of the model. Rather than start with a finely gridded geocellular model of the reservoir and then coarsening it to include some elements of the overburden and surrounding geology the NGCAS workflow started by using regional data to define and develop boundary conditions for the refined model of the geological storage system at the site. It resulted in a more rigorous definition of connectivity between the storage compartment and the regional system and the interconnectivity between the elements of that regional system that might constitute potential migration pathways and hence risks.

NGCAS studied regional 2D and 3D data sets and then focused down into the storage target. Since the regional picture had been defined it was possible to perform multi-component simulation within the reservoir with prevailing and future boundary conditions established to a high degree of confidence. This reduction in bounding uncertainty resulted in a simplification of the risk analysis procedure so that the major risks were immediately obvious and could be targeted for further work.

The result of forward modelling of CO_2 storage over 1000 year period investigated using SIMUSCOPP indicated that the main geological processes by which CO_2 might leak from the reservoir are lateral flow in the underlying aquifer and diffusive flow through the overlying mudstone cap rock (seal). Base case and worse case assumptions show no release of CO_2 to surface via these mechanisms in the 100-year period. The predicted migration rates under base case assumptions are 50m above the reservoir in the seal for vertical migration and lateral migration in the underlying aquifer is less than 10m after 1000 years.

These results suggests that the geological integrity of CO_2 storage is likely to be effective in the North Sea Forties Field on a 1000 year timeframe. This reflects the favourable geological characteristics of the sealing formations,which have been effective for trapping oil and which are also favourable for CO_2 storage.In the case of the Forties field it was concluded that there were two migration pathways with higher than average risk: geological leakage through the overburden and leakage through new and existing wellbores that penetrate the seal. This in itself was an important conclusion.

From an economic perspective it was a new look at an established process. BP had previously looked at EOR (Enhanced Oil Recovery) purely from the point of oil recovery, but NGCAS was notable for combining this with the study of incremental CO_2 storage. Modelling of CO_2 storage combined with enhanced oil recovery for the North Sea Forties Field showed that:

- Oil recovery can be increased by 10%
- Up to 50% of the hydrocarbon pore volume could be filled with CO2 during storage

The Risk Analysis of CO2 storage was investigated using the FEPs method.This concluded two principle migration (leakage) pathways: 1) geological, and 2) wells. The result is a direction for further work on risks, both continuous and discrete: firstly to better characterise the mechanisms that might lead to and promote well-bore leakage, this was beyond the original project scope. These studies should look at cements and metallurgy (which may have a major impact on the economic feasibility of any storage project); and secondly to better characterise the geological overburden, its response to the altered mechanical stress regime created by CO_2-rich fluids, its chemical reaction with those stored and migrating fluids, and the behaviour of any faults within it. This is considered to be secondary since in the case of an established hydrocarbon reservoir known to have been “filled-to-spill” (i.e., structurally full) and with little evidence of further migration through superimposed sediments, it is evident that the sealing mechanism is good over geological time and that there is either no leakage into the aquifer (e.g., owing to earthquakes) or that there is constant but gradual replenishment of hydrocarbons.

This clear methodology makes NGCAS potentially useful in the communication of geological CO_2 storage to a wider audience. NGCAS serves as an important case history for geological storage. The study illustrates the need for an integrated approach using seismic and well data, advanced modelling and risk analysis techniques, etc. It illustrates the level of understanding achievable with advanced oil industry data and tools adapated for CO_2 storage.

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